NREL Western Wind and Solar Integration Project
Stakeholder Conference Call March 24, 2009

This stakeholder conference call/webcast on the Western Wind and Solar Integration Study (WWSIS) was a follow-on to the August in-person meeting. In August, the discussions centered on renewable resource inputs, assumptions regarding load and transmission inputs, and preliminary statistical and production simulation analysis. The two main action items to come out of that meeting were:

1. Move ahead with the development of two additional scenarios:

    - Mega Project – essentially a least-cost delivered energy scenario that includes new transmission.
    - Local Priority – about halfway between Mega Project and the In-Area scenarios.

2. Wind data – severe ramping events in the wind data were found to be due to data corruption glitches and the data needed to be reviewed and revised.

During this conference call, NREL and 3TIER discussed the data issues that had been resolved and the GE team presented their progress on scenario development, statistical analysis, production simulation analysis, and new scenarios under consideration.

The GE presentation can be downloaded at:
http://wind.nrel.gov/public/WWIS/stakeholder%20meetings/3-24-09/StakeholderCallMar2409.pdf

Data Issues

Cameron Potter of 3TIER began by focusing on the wind data. The sheer size of the dataset had been posing a problem. 3TIER knew there could be some discontinuities in a dataset of this size, and they had corrected most of them. The glitch in the wind results showed that some were still to be found. A part of the problem was a failure in the model itself arising from the discontinuities. They found flags in the model output showing a change in model behavior at those points. 3TIER ended up rerunning certain portions and generating a new dataset. They also noted that some of the data was getting corrupted during data transfers. 3TIER used slower transfer techniques and verified that the revised dataset was correct when making copies to drives.

Debbie Lew of NREL noted there were two places on the NREL website that the wind data could be accessed. She encouraged people to examine the data and provide any comments to NREL. The wind data can be downloaded at http://www.nrel.gov/wind/westernwind/ and both the wind and solar data can be downloaded at the beta site: http://mercator.nrel.gov/wwsi

Work Plan

Dick Piwko of GE described the status of the GE analysis. He said the work plan is the same as presented in August (Slide 2) but the dates have changed. The data issues pushed the deadlines back. GE has pretty much completed the top box culminating in this Stakeholder Meeting (early March 2009). GE has started some work on the next stage, validating the quasi-state-state (QSS) methodology and tools. The team will also begin analyzing the Mega Project and Local Priority scenarios and will discuss what the two additional scenarios should look like.

Revised In-Area Selection

Kara Clark of GE explained that with the new dataset, NREL and GE had taken the opportunity to make changes in the site selection process including additional exclusions, based on factors such as proximity to recreation areas e.g., (Forest Service campgrounds). Additionally, while site selection still looks at energy value, capacity value and geographic diversity, the capacity factor now consists of an average of all three years of potential wind production, not one. The footprint has also been redefined to better match WestConnect and respect transmission barriers, resulting in a chunk of Idaho being removed and eastern Nevada being included. Ultimate site selection, however, for the In-Area scenario analysis is based on state boundaries, not transmission areas. The new In-Area footprint (Slide 5) has a part of Utah now included in Nevada and a chunk of Idaho removed from Wyoming. There are a total of about 25,000 sites included in the scenario analysis.

The In-Area scenarios investigated include:

- 30% wind, 5% solar energy in footprint and 20% wind, 3% solar in the rest of WECC
- 20% wind, 3% solar in footprint and 10% wind, 1% solar in rest of WECC
- 10% wind, 1% solar in footprint and 10% wind, 1% solar in rest of WECC

Solar energy includes 70% Concentrating Solar Power (CSP) that has 6 hours of thermal storage, and 30% PV. Approximately 1,000 wind sites with a capacity of 30 MW each were used in the 30% penetration case. Solar sites are 100 MW each. Total in-footprint solar capacity was 5,800 MW for the 5% solar level. Wind capital cost was assumed to be $2,000/kW and solar was $4,000/kW, leading to a total capital cost of about $83 billion for all the sites (Slides 9 & 10).

There was some discussion on the criteria used to exclude sites and whether the criteria could give any ammunition to opponents of new renewable energy power plants. Ms. Lew explained that the focus of the study was operational impacts of wind and solar, rather than specific siting of wind and solar. NREL used standard environmental exclusions, such as national parks and urban areas, plus additional exclusions to remove areas that were unlikely to be developed such as high elevations, and sites within 5 km of a forest service campsites.

Another caller asked whether GE and NREL may assess different future load profiles, such as if loads are flattened by DSM or electric vehicle charging. Gary Jordan of GE said there are no plans to do so, but there are two scenarios that remain undefined, and that could be one of them. Ms. Lew said plug-in hybrid electric vehicle charging at night could be a sensitivity scenario or mitigation strategy, and that NREL was also interested in exploring this.

There was also some discussion on whether the site selection corresponded with the sites being chosen for the Western Renewable Energy Zones (WREZ) project. This study and site selection was conducted before the WREZ areas were proposed. The team will be looking at the work coming out of WREZ as more results become available, but they pointed out that this study examines penetration rates on a regional basis and does not attempt to do any detailed transmission planning, so specific site selection has less impact on the overall results.

Statistical Analysis on In-Area Scenario

Time Series Plots and Daily Profiles

Lavelle Freeman of GE describes the statistical analysis of the study footprint. He defined net load as the instantaneous system consumer load minus the generation output of wind and solar. Net load is the amount of generation required from other units. Key issues addressed in the time series plots and daily profiles are:

- Coincidence of load, wind and solar.
- Impacts on net load peaks and valleys.
- Increases in ramp rates.

The analysis examined monthly and hourly energy output. Some observations on the results are:

- January 2004 is a down year for wind compared to 2006.
- 30% wind is an annual average figure and monthly penetration varies tremendously. For example, 55% of energy generation in April 2006 is from wind and solar, but the contribution from wind and solar is less than 20% in July and August (Slide 17).
- The wind resource in Arizona is not particularly great and the load is very high. Arizona needs a lot of low-quality wind sites to meet the 30% goal. Wyoming has low load and high wind resources and therefore, does not need very many wind sites. This can lead to higher variability in Arizona. For example, 68% of load in Arizona in March 2006 is met by wind and solar generation (Slide 18).
- Wind tends to drop in the mid-morning but that is when solar and CSP kick in. Wind and solar energy production tend to be complementary. CSP is assumed to have 6 hours of storage (Slide 19).

The net load duration curves highlight the large impact of 30% variable renewables, which pushes down the duration curve so that the system is operating below the minimum load point of 22,200 MW more than 57% of the time. Additionally, wind penetration reaches a maximum of 113% for some hours of the year. CSP output is zero for 40% of the year and PV for half the year. Maximum CSP penetration is about 12% (Slide 20). Overall, 2004 is a bit of a down year compared to 2005 and 2006. The peak is at about 50,000 MW and the minimum load occurs in April for two of the three years and in October for the third

On a seasonal basis, there is more wind in January and April for 2006 and less wind in July, but wind rises generally with load through the year. In January, when load is rising, wind is flat or dropping slightly (slide 22). In January, there also tends to be less solar energy. There is more solar energy in April and July and less in October. Surprisingly, there is more energy from CSP in April than July. GE explained that the monsoon season in the Southwest starts in July and this reduces solar production. June tends to have more solar energy than April. Also, variability is driven mostly by wind, which exhibits a largely random pattern as opposed to load and solar that have a fairly regular pattern over the course of a month (Slide 24). A plot of total load over a month shows a substantial increase in net load variability with 30% wind penetration (Slide 25). Taken over the whole WECC region, however, the impact of wind is far less dramatic (Slide 26). This shows how larger balancing area cooperation can serve to help decrease the overall variability of wind.

<u>Period-to-Period Variability Analysis</u>

Variability (Slide 28) is an important issue as extreme highs and lows are exacerbated by wind energy on the grid, which is a concern for grid operators. The statistics used to characterize variability are:

- Delta – the difference between successive data points in a series, or period-to-period ramp rates. A positive delta is a rise or up-ramp. A negative delta is a drop or down-ramp.
- Mean – the average of the deltas.
- Sigma – the standard deviation of the deltas.

The scatter plots of wind deltas versus load deltas for the 30% penetration case (Slides 29 & 30) lead to some observations:

- The maximum load down ramp is about 5,000 MW.
- For 30 hours over the 3 years, wind drives the net load down ramp.
- During times when load is ramping up and wind is ramping down, there is a cumulative total of 138 hours over three years where wind production has fallen off significantly enough that there may be insufficient generation to meet load.
- With each season on a different plot – several points are at extremes but not as many as expected and there are more instances of reduced risk when ramps offset each other than when they don't.

The average daily profiles of deltas over a year show that 10% and 20% wind do not shake the system very much more than normal load variability (Slides 31 & 32). The biggest up ramp and down ramp for the 10% case in any hour for 2006 is a max 1-hr rise of 5,128 MW in hour 16 (bigger than load) and a max drop of 4,345 MW in hour 23 (about same for load). In the 20% case, there is a little more variability; the max down ramp is about 4,500 MW at 3 PM, which is more than load alone, and the max up ramp is 6,885 MW at hour 16. The 30% case however, seems to really start pushing the envelope with a max up ramp of 7,874 MW and a max down ramp of 6,851 MW (Slide 33). Additionally, the difference between 10% and 20% is much less than the difference between 20% and 30%. Moving from a 20% penetration to a 30% penetration shows a significant increase in variability. The average daily profile by season for the 30% case shows a lot is happening between 2 and 4 PM, both on the upside in July and the downside in

January. Additionally, the extreme deltas are more pronounced in evening hours during spring and fall.

Slide 41 presents a statistical analysis of changes as compared to the baseline. In the 10% case, variability actually decreases as this represents the best renewables sites. Statistically speaking, the 10% case is not significantly different from inherent load variability. Variability gets worse with the 20% and 30% cases, with an especially large increase when moving to from 20% to 30%. However, examining the deltas from state level up to a WECC region-wide level shows clear benefits can be derived from aggregation. A larger area tends to mitigate the relative impact of large ramps (Slides 43-45).

<u>Operational Analysis on In-Area Scenario</u>

Gary Jordan of GE presented the results of the operational analysis on the In-Area scenario. The operational analysis used the following assumptions:

- 2017 fuel prices – coal at \$2.00/MBtu and natural gas at \$8.00/MBtu (2007\$).
- Carbon price set at \$30/ton.
- Energy velocity – WECC planned capacity additions of 13 GW plus 11 GW added to maintain reserve margin.
- Peak load – NERC ES&D projections.
- Economically rational WECC-wide commitment and dispatch (Slide 47).

Unfortunately, there was a bias in the wind forecast that affected operational analysis significantly. Therefore, the same analysis was run with a reduced forecast (10% in-footprint and 20% out-footprint). In the presentation the unbiased forecast is the 'R' scenario. The team also ran the analysis on a perfect forecast, labeled 'P' in the presentation (Slide 48).

The analysis of spot price for various regions for the different penetration cases resulted in the following observations:

- Spot prices drop in the baseline, 10% and 20% cases, then go up in the 30% case.
- At 30%, there are higher spot prices for about half the year and lower prices for about half the year. In the 30% case; there are more times when wind is over-forecasted and operators are caught outside the time where they can respond with relatively cheap units. In the 10% case, spinning reserves are adequate but the team did not change spinning reserve requirements and this starts to show in the higher penetration cases. Additionally, forecast bias is starting to come into play in the 30% case.
- With a perfect forecast, the spot price drops as more wind is brought in because operators know when the wind is coming. As penetration levels increase, the benefits of forecasting become more apparent.

The generation by type within the study area changes as more wind and solar are added to the system. Combined cycle units are the ones most displaced; geothermal, hydro and nuclear power remain the same; generation from gas turbines drop until the 30% scenario where it then increases; coal units remain the same until the 30% scenario when their generation drops slightly (Slide 54). Combined cycle units are the marginal units and therefore, the most affected. The need for gas turbines drops with the 10% and 20% cases but in the 30% case gas turbine generation increases (Slide 55). The annual number of starts for combined cycle, gas turbine, and coal units also increases as they tend to be cycled off more often with the variations in wind energy output. Overall, total generation output remains relatively stable (Slide 58).

The total operating costs (fuel, start-up, O&M) are affected by increasing renewables. Wind comes in as a price taker with operating costs assumed to be zero. However, as more renewable energy is added, savings decrease (diminishing returns). Average operation savings dropped from $89/MWh to $79/MWh at 30% penetration, which is a drop but not a particularly precipitous one (Slide 60). Emissions of NO_x, SO_x, and CO_2 drop as renewable energy penetration increases for both In-Area and all of WECC (Slides 62 and62) NO_x drops continuously; SO_x doesn't drop until 30% wind when coal generations drops; CO_2 increasing decreases with a larger decrease when coal drops off. Generator revenues drop with increasing penetration, as more price takers are added to the market. In the study area, total generator revenues drop from about $34 billion to $27 billion with 30% penetration.

<u>Weekly Operational Analysis</u>

This analysis examined the hourly operation for two specific weeks in mid-April and mid-July to determine the hourly variation in generation by type as renewable energy penetration increases. The study area is a net exporter of energy and therefore the team also looked at load plus exports. Main observations from the analysis include:

- Minimum loads are not as severe when exports are factored in.
- At 10% penetration, unit dispatch is fairly constant across the board.
- At 30%, renewable energy generation exceeds load on April 15th (Slide 71) but the system is exporting. With exports factored in, net load does not fall below 6,000 MW (Slide 72).
- Wind forecasts are critical.
- No significant issues up to 20% penetration but impacts get much more severe as 30% penetration (Slide 79).

Looking at the system dispatch data for the week in April (Slide 74) shows that nuclear is unaffected (dip in graph is a maintenance outage) except during a few extreme times in the 30% case. Coal is only slightly affected at 10%, but increasingly pushed down at 20% and at bare minimum in 30% case. In the 30% case, combined cycle generation is almost gone. By comparison, dispatch in the week in July (Slide 78) is fairly tame as there is far less wind generation into the system (i.e., 30% is not 30% in every month).

There was some discussion concerning the changes in number of generator starts and that there was not a big increase in starts until penetration reached 30%. The GE team noted that two things were happening:

- The gas turbines see the most change. They are at partial load and cover some of the peaking portion therefore, gas turbines see a decrease in starts until 30% wind, when the GTs are cycled off and then need to be cycled back on.

- Some of the change is a function of the forecasts. If operators get caught short due to an under-forecast, they have to make up that energy in real time with peakers.

It should also be noted that the change in the study footprint penetration from 20% wind (3% solar) to 30% wind (5% solar) is accompanied by a change in the rest of WECC from 10% wind (1% solar) to 20% wind (3% solar) which has a great impact on the study footprint. There was also some discussion about doing the analysis as a single balancing area. Up to this point, analysis has been done on the WestConnect footprint as if it is a single balancing area, but we will analyze individual balancing areas in future analysis.

Additional Study Scenarios

Nick Miller of GE described the two new scenarios. The two new scenarios, Mega Project and Local Priority, are variations on the In-Area scenario. The group had discussed a menu of scenario options in August but it had been decided that for now, GE would focus on these two variations that make better use of good wind sites complemented with new transmission. There are still a couple of open slots for new scenarios.

GE used an algorithm to swap out sites after accounting for transmission and capital costs. GE is trying to make use of cost of capital for building wind vs. transmission to meet the 30% target. The capital cost for wind was assumed to be $2,000/kW.

The Mega Project scenario swapped out sites to take advantage of better wind sites in Wyoming and then applied the needed transmission. The scenario does not make use of existing transmission lines; if transmission capacity is needed, it is built. The model overbuilds wind compared to transmission capacity at a 70% discount factor, i.e., only 700 MW of transmission is built to move 1,000 MW of wind. Under this scenario, wind capacity in Arizona decreases by 9,330 MW and wind in Wyoming increases by 11,430 MW. New transmission is assumed to cost $1,600/MW-mile. GE limited capacity to 30 MW per wind site and 100 MW per solar site to deal with partial capacity plants. Transmission ratings are 1,000 or 1,600 MW/circuit (345-kV and 500-kV, respectively). GE did not include any HDVC until transmission was needed that was more than what double-circuited AC could provide. They also selected in-footprint routes when possible and ignored smaller voltage level connections (Slide 84).

The Local Priority scenario is a mid-point between the In-Area and the Mega Project cases. GE wanted to try to reflect that local projects have local benefits (taxes, benefits, etc.) with local political support. This was done by giving a capital cost discount (10%) to in-area wind and solar sites to make them more economically attractive. This changed site selection and transmission needs. The new transmission can be all AC; there was no need for the HVDC tie. In this case, the algorithm added the best wind sites in Wyoming and removed the poor-quality wind sites in Arizona but did not start including marginal sites (Slide 86). Wind capacity in Wyoming increased by over 5 GW and decreased in Arizona by 3.5 GW, and in Nevada by 3.6 GW with smaller changes in Colorado and New Mexico. Overall, there was 3,780 MW less wind in the local priority scenario than the in-area scenario at about the same amount of solar. About 2100 GW-miles of transmission was needed. The transmission paths have been rationalized and the resulting transmission tends to mesh well with the overall Western Interconnection transmission planning that is currently ongoing.

Next Steps

The next step for the modeling team is additional analysis of the In-Area scenario examining reserve requirements and conducting a quasi-steady-state (QSS) analysis. The team will also conduct detailed analyses of the Mega Project and Local Priority scenarios and develop two additional scenarios for consideration.

Discussion

A caller asked if the team would be looking at the advantages and disadvantages of diversity in the Mega Project analysis. GE noted that diversity ended up in all the scenarios and the Mega Project actually is a bit less diverse due to the bigger build-out of wind and solar in the regions with the best resource. For example, there are 20% fewer wind sites required in the Mega Project scenarios because the wind resource is better at the remaining sites. As to whether having a better resource with fewer sites will be a net positive or net negative, that is hard to determine, as the sites will be clustered together more.

A caller asked if the team had the ability to add flexible resources when including the generation needed to meet reliability in the base case. GE said this was not really something they were concerned about and the generation added was mostly in the form of peaking units. GE noted they could not change too many things or then would be unable to know where the impacts were coming from.

A caller asked whether the team thought 30% renewable penetration was doable or did the work GE had done indicate it might be too difficult for the grid to handle. The GE team said they thought it would be challenging, especially at certain times of the year (spring and fall) but creative solutions could and would be applied, and/or the excess wind generation may have to be spilled or wind plants curtailed at certain times. Also, GE noted they were still in the early stages of the analysis and they have yet to do the detailed QSS analysis so it was too soon to make any real judgments. The other scenarios too may show a different picture and in a sense the next two scenarios are more realistic in terms of what might really happen in the next decade.

The next stakeholder meeting will be in July, place and date to be determined.